

In sum, MMS should value oil disposed of at the lease under an arm's-length buy/sell agreement at the price stated in the "sale" component of the contract, unless that price is unreasonably low because of the misconduct of the parties.

d. **MMS Must Not Shrink the Scope of the Gross Proceeds Approach**

When MMS comprehensively examined royalty valuation for oil in the 1980s, it determined that it should continue to rely on transactions in the marketplace nearest the wellhead, particularly those entered into by persons with opposing economic interests.

Value in these regulations generally is determined by prices set by individuals of opposing economic interests transacting business between themselves. Prices received for the sale of products from Federal and Indian leases pursuant to "arm's-length contracts," in many instances, are accepted as value for royalty purposes. However, even for some arm's-length contracts, contract prices may not be used for value purposes if the lease terms provide for other measures of value ... or when there is a reason to suspect the bona fide nature of a particular transaction. *Even the alternative valuation methods, however, are determined by reference to prices received by individuals buying or selling like-quality products in the same general area who have opposing economic interests.*

53 Fed. Reg. 1184, 1187 (1988) (emphasis added). The contrast between the current rule and the proposed rule is thus like that between night and day. The proposed rule presumes that all transactions in which there is the slightest possibility of a bad faith valuation are invalid indicators of market value. It then rejects reliance on any information from the wellhead market and uses a kind of netback approach to value oil, beginning with prices in Los Angeles, San Francisco, and Cushing, Oklahoma. The current rule, on the other hand, looks at a particular transaction and inquires whether it produces a value that is unreasonably low when compared with other comparable transactions at the wellhead in the same field. 30 C.F.R. § 206.102(b)(1)(iii) (1996).

We suppose that MMS has the right to change its mind on how it should approach royalty valuation in light of the experience it has accumulated under the 1988 rules. But the rulemaking notice and the rulemaking record fail to refer to **any** evidence that MMS cannot assure compliance with the rules by auditing particular transactions for bad faith dealing. MMS has cited no evidence that oil subject to crude oil calls or exchange agreements is typically valued by the parties at prices lower than those obtained by parties selling comparable oil under arrangements that even MMS would concede are truly at arm's length. Indeed, if MMS has evidence of such undervaluation, it presumably is enforcing the current regulation to assure that the proper value is being paid. Nothing in the record

indicates that the current rules are in the least degree unworkable in dealing with possible undervaluation. MMS's accumulated experience offers no support for the proposed change.

3. **MMS Wrongly Assumes that Fair Market Value Is a Single Price.**

The vast majority of pricing provisions in sales contracts remain related to prices listed in crude oil price bulletins, or "postings." While postings may be a final price offered for oil, perhaps more often they serve as benchmarks from which fair market prices are negotiated.

Accordingly, if MMS were to select 10 oil fields at random, and prepare a chart for 1995-96 plotting the arm's-length values on which federal lessees paid royalties against the posted prices for the fields, the chances are good that MMS would find a band of values in each field for each month. Some would be below the posted prices, as can be the case with low-gravity, sour crude oils in the Rocky Mountain region. Some would be at those prices, some above the highest posted price. Many reasons could account for the differences, but the three most likely reasons would be that (1) different qualities of crude oils in different areas face different balances of supply and demand, (2) some sales would be under term contracts while others would be under spot contracts and (3) willing buyers and willing sellers negotiate different prices for essentially similar commodities. MMS readers of these comments will know the third point is true from their personal experience in buying homes and automobiles.

Looking at this imaginary chart -- which we would encourage MMS to actually construct from its extensive data base -- what could a reviewer infer about the fair market value of a given crude oil in a given field in a given month? A reviewer would correctly infer that all the prices under arm's-length contracts represent a fair market price. All were arrived at through free negotiations, and negotiated prices are what fair markets are all about.<sup>5</sup>

Prices are posted not only by integrated oil companies, but also by independent refiners such as Koch Oil, Scurlock Permian, and independent marketers such as EOTT Energy. Posted prices must be competitive and market responsive if a company is to be successful in purchasing crude. Posted prices are used by buyers and sellers to negotiate absolute prices which may include an adjustment for gravity and/or a premium or deduction. Market premiums are added to the posted price and paid to producers when a purchaser is willing to pay more than the gravity-adjusted posted price at the lease. Premiums vary in amount depending on location, volume, grade, and type of crude. Premiums are driven by competition and are negotiated on an arm's-length basis between producers and purchasers

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<sup>5</sup> We assume MMS has not abandoned its longstanding view that fair market value does not mean the highest possible price. *See, e.g., NRDC v. Hodel*, 865 F.2d at 312.

taking highly localized supply and demand factors into consideration and, thereby, defining the market values of lease crude in the field.

Perhaps it was not MMS's intent to suggest that there is a national fair market price for oil, but that is the most plausible reading of the preamble to the proposed rule. The agency has inappropriately abandoned its well-founded recognition that free markets produce multiple fair market prices. This action is in conflict with the Department's prior policies. For example, in *Conoco, Inc.*, 110 IBLA 232, 244 (1989), the IBLA upheld the valuation of non-arm's-length transactions which were within a range of arm's-length prices for natural gas liquid products. The Board specifically rejected MMS's attempt to value sales that fell below the range at a price representing the average of the high and low prices; MMS was required to value the transaction using the low-end of the range. Similarly, the Assistant Secretary, Land and Minerals Management, has issued a policy paper governing the application of the benchmarks under the 1988 gas valuation rules, and that paper also endorses the acceptability of non-arm's-length prices within the range of comparable arm's-length prices.

**4. MMS Wrongly Assumes It Is No Longer Feasible to Value Non-Arm's Length Sales by Comparing Them With Arm's-Length Sales.**

As we have already explained, the 1988 rules require that when oil is not sold under an arm's-length contract, the value for royalty is established by examining comparable arm's-length transactions in the wellhead market. This was no innovation. It reflected the culmination of years of case-by-case agency adjudication of royalty appeals.

The seminal decision in this area is *Getty Oil Co.*, 51 IBLA 47 (1980). There Getty entered into two agreements with Transcontinental Gas Pipe Line Corporation ("Transco"), one a sales contract, the other a transportation contract. Under the transportation contract, Transco agreed to ship a portion of the natural gas produced from Getty's offshore lease from the Gulf of Mexico to a connection near a refinery in Delaware. Getty sold the transported gas to its wholly owned subsidiary, which operated the refinery and which used the gas in a hydrocracking process. Under the sales agreement between Getty and its subsidiary, the subsidiary paid Getty the same price for the gas that Transco paid Getty under their sales contract.

The U.S. Geological Survey had assessed additional royalties against Getty on the theory that Getty could have abrogated its contract with its subsidiary at any time and sold the gas at a higher price. Rejecting this argument, IBLA ruled that "a parent corporation and its wholly owned subsidiary may enter into a valid contract." *Id.* at 50. IBLA found it "error, in the absence of even a suggestion of impropriety, for GS to disregard the validity of Getty's agreement" with its subsidiary. *Id.* at 51.

Although contracts between a parent corporation and its subsidiary may not be at arm's length, they may result in a fair

market price. If a transaction is not at arm's length, some other manifestation that the price is nonetheless an accurate portrayal of the article's worth is required. It must be a price which independent buyers in arm's length transactions would be willing to pay.

*Id.* Since the price Getty received from Transco and from its subsidiary were equal, IBLA found that the subsidiary's price reflected the fair market value of the gas.

Although nothing in *Getty Oil* suggests that the rule should be different when the affiliated purchaser does re-sell the production, the facts in that case did not squarely present the issue. Subsequent IBLA decisions addressed this situation, however. In each one, IBLA compared the non-arm's-length sale with a sale by another producer to a first purchaser.

The first proof of this point came in a case concerning the valuation of royalties on zinc concentrates. *Amax Lead Company of Missouri*, 84 IBLA 102 (1984); *Amax Lead Company of Missouri (On Reconsideration)*, 99 IBLA 313 (1987). There the issue was how to value zinc sold under a non-arm's-length contract to a smelter in Illinois, which then processed the zinc for shipment and resale in markets on the Atlantic Seaboard. 84 IBLA at 103-04; 99 IBLA at 316. Both the MMS and the IBLA agreed that the value was to be determined by reference to prices received by unaffiliated producers of zinc who sold the concentrates to the Amax smelter.

The next case addressing *Getty Oil* in the context of the resale of oil or gas is one of IBLA's leading precedents in the area of royalty valuation, *Transco Exploration Co. & TXP Operating Co.*, 110 IBLA 282, 96 I.D. 367 (1989), *appeal filed* No. 90-191-L (Ct. Fed. Cl. Mar. 1, 1990) ("*Transco*"). In *Transco* the issue was whether Transco Exploration Company ("TXC") had correctly valued the royalty on gas it produced on lease OCS-G 1960 and sold to its affiliate, Transcontinental Gas Pipeline Corporation ("Transcontinental"), for resale in the interstate gas market. TXC over the course of three years routinely agreed to lower the sales price to Transcontinental. 110 IBLA at 285-300. IBLA agreed that MMS correctly had looked to see what other unaffiliated producers who held an interest in the same lease had sold the gas for. *Id.* at 336.

IBLA followed its *Transco* approach in *Ladd Petroleum Corp.*, 127 IBLA 163 (1993). There again royalty was valued at the price that an unaffiliated party had paid to purchase residue gas from the owner of the processing plant (whose proceeds the lessee shared in under a percentage-of-proceeds contract). *Id.* at 174. And in *Mobil Oil Corp.*, 112 IBLA 56 (1989), IBLA recognized the difficulty a lessee selling to an affiliate would have in obtaining the price data from its competitors in order to prove that its non-arm's-length contract had a price comparable to what parties would pay at arm's length. As a result, IBLA suggested that it would be easier for MMS to assemble that data from other producers.

In effect, requiring a lessee to make such a showing comports with the option extended to lessees by the Board in *Getty Oil Co.*, 51 IBLA 47, 51 (1980), which held that the Department may value production for royalty computation purposes on the basis of prices derived from non-arm's-length transactions where such prices are reflective of the fair market value of the production. However, we note that a lessee could have difficulty in making a showing as to the validity of the price it used to value [natural gas liquid products] NGLP, as compared with other contract prices, since a lessee will not likely have complete information regarding all sales contracts in an area. In fact, a lessee might run afoul of price-fixing restrictions if it attempted to assemble this data. On the other hand, MMS, which receives contract information from all Federal lessees, is in a much stronger position to assert, and defend against challenge, a determination as to whether a particular contract price is permissible.

*Id.* at 63-64 n. 8 (emphasis added).

However, at the April 17, 1997, rulemaking hearing in Houston, Texas, Dr. Donald Sant, Deputy Associate Director for Royalty Management, disclosed for the first time that MMS believes that there is not enough information on arm's-length sales at the wellhead for MMS to employ its benchmarks. Transcript of April 17, 1997, hearing in Houston pp. 160-62.

Dr. Sant. . . . We did some special audits of the California oil market and we found when there were truly arm's-length transactions, they were at premiums above postings. Those arm's-length transactions weren't necessarily and seldom were at or near the lease.... If other cases where companies do post prices, they report postings, make no attempt to see if there is any arm's-length transactions in that field in those particular areas.

*Id.* At 160. This is a very meager indictment of the lease market for crude oil. What it says is that MMS audited certain integrated oil companies producing and operating refineries in California. Those companies presumably were taking most of their own production to their refineries, so they did not possess a lot of data on arm's-length sales. These audits, as best one can tell from Dr. Sant's description, did not attempt to use MMS's data base to look for arm's-length transactions in the relevant fields. Instead, contrary to IBLA's teaching in *Mobil Oil Corp.*, the special audits improperly placed the burden on the lessee to ferret out what other companies were getting at arm's length. When the companies did engage in arm's-length transactions, they usually did so downstream of the lease market. Not

surprisingly, those downstream transactions received higher prices than companies were willing to issue postings for in the upstream market at the leases.

At bottom, then, MMS is proposing to abandon its carefully crafted benchmark system because it is unwilling to follow the directive of the IBLA to use the data it already possesses in its AFS database. And it finds fault in the lease market because transactions are occurring **downstream** at prices higher than the posted prices offered at the leases. MMS is therefore inappropriately comparing transactions at dissimilar points in the stream of commerce in crude oil.

#### MMS RATIONALE FOR USE OF NYMEX AND ANS PRICES

Citing "mounting evidence that posted prices frequently do not reflect value in today's marketplace," 62 Fed. Reg. 3744, MMS proposes to rely instead on the monthly "average of the daily NYMEX futures settle prices for the Domestic Sweet Crude Oil contract for the prompt month," *id.* at 3745, for oil to be delivered at facilities in Cushing, Oklahoma. If the lease in question is in California or Alaska, however, MMS proposes to rely on "the daily mean Alaska North Slope (ANS) spot prices for the month of production published in an MMS-approved publication...." Proposed § 206.102(c)(2)(ii), 62 Fed. Reg. 3753. Either average price would be adjusted "for applicable location and quality differentials" to approximate the value of the lessee's oil at the wellhead. Proposed § 206.102(c)(2)(I) and (ii), 62 Fed. Reg. 3753.

MMS believes that the NYMEX price is the superior measure of crude oil value. It resorts to the ANS spot price for Alaska and California simply because their "distance from the mid-continent markets would lead to great difficulties in making meaningful adjustments from the NYMEX price." Accordingly, "MMS believes that a more localized market indicator would better represent royalty value." 62 Fed. Reg. 3745. Even east of the Rockies, MMS concedes that reliance on NYMEX will involve "difficult location and quality adjustments." *Id.* Even so, MMS would adopt the NYMEX price as the nationwide standard because it "represents the price for a widely traded domestic crude oil (West Texas Intermediate at Cushing, Oklahoma), and there is little likelihood that any particular participant in NYMEX trading could impact the price." *Id.* More significantly, "MMS believes that today's oil marketing is driven largely by the NYMEX market." *Id.* at 3746.

But the real issue is not whether NYMEX is driving oil marketing or whether oil marketing is driving NYMEX; the issue instead is whether the NYMEX price is a workable proxy for the price of oil at the wellhead. The actual commodity traded in the NYMEX is a contract right to wet barrels, so-called "paper" barrels. There is, of course, ultimately a link in the price of wet and paper barrels, for occasionally a futures trader holding a contract actually has to either accept or provide delivery of real barrels of oil. Usually, however, the trader exits the market by taking an offsetting position, that is,

removing an obligation to deliver barrels by obtaining an equal obligation to buy barrels in the same month, and taking his profit or loss in cash. This makes the two markets distinct enough to keep the NYMEX price removed from the reality of the market at the wellhead in the month of actual production.<sup>6</sup>

DPC's concern is that, according to NYMEX's own data, speculators are far more active in the paper-barrel market than producers are. (Exhibit 18.) Such heavy participation by persons not directly involved in the production and purchase of crude oil underscores the differences between the cash market for wet barrels and the futures market for paper barrels. The motivations of these persons differ from those producing and buying real barrels. Speculators sometimes base their bidding on factors irrelevant to or in addition to the physical supply of and demand for oil, and often alter their positions (and thus the price) because of occurrences in foreign stock markets or in futures markets for other commodities. E.N. Krapels, "Why Energy Futures Markets Merit Support Amid Latest Controversy," *Oil and Gas Journal* 21, 23 (Feb. 10, 1997) ("decision on the part of the speculator to go short in the oil market may have had more to do with changes in the Nikkei or in other commodities than with anything happening in oil").

The NYMEX price is determined in a market that is largely insulated from the risks facing parties in the lease market for crude oil. As the NYMEX briefed you in October 1996, the Exchange requires participants to exceed minimum requirements for financial integrity. Participants must contribute to the NYMEX Guaranty Fund which acts as a safety net to assure the performance of the contract. The Exchange limits the value of the futures "positions" a participant may hold, and limits the number of contracts it may hold. Holders of futures contracts must maintain deposits, called "margins," for each contract which increase as the given contract nears delivery. In short, through these restrictions and through the standardized terms of the futures contract, NYMEX assures that the only risk a participant faces is the risk of price change. In dramatic contrast, a lessee selling in the lease market faces the risks that its wells will not produce (because of accidents, equipment failures, and the like), risks that it will incur unexpected costs, any risks that its purchaser will be unable to perform for a variety of reasons. These are in addition to the risk of price

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<sup>6</sup> MMS's proposal illustrates the problem. To value production in September 1996, MMS would use the NYMEX price generated in trading between August 21 and September 20 for oil to be delivered in October 1996. 62 Fed. Reg. 3745. MMS recognizes that what NYMEX is trading during that period is not September oil. But it justifies this approach by observing that "[a]lthough it is a futures price, it would reflect the market's assessment of value during the production month." *Id.* This view is not well-considered. During the period of August 21 to September 20, NYMEX is trading not only contracts for October delivery, it is also trading contracts for delivery in any of the subsequent 30 months. All of this trading reflects in some sense "the market's assessment of value during the production month," but **none** of this trading reflects the market's assessment of the value of oil **delivered** in September 1996.

change with which a lessee must contend. The assurances NYMEX provides give the oil its contracts provide a premium value over riskier transactions in the wet barrel market.

In sum, DPC objects to the use of a NYMEX based price to value oil at the wellhead because of differences in:

- ▶ **Commodities Traded:** NYMEX trades contract rights; the lease market trades barrels of oil.
- ▶ **Timing:** NYMEX prices value oil at least one month earlier than the month of production; the lease market values oil during the month of production.
- ▶ **Location:** NYMEX values oil delivered in Cushing, Oklahoma, and MMS will have to make price adjustments it admits will be difficult -- and which will require a massive new federal data collection and digestion effort -- to approximate values at the wellhead; the lease market values oil at or near the wellhead already.
- ▶ **Risk:** The NYMEX contract has only one of the many risks the wet barrel sales contract has, and essentially no risk of non-performance. The NYMEX price therefore commands a premium.

With respect to California and Alaska, the proposed rule would use the ANS spot market price as the benchmark for valuation, in place of the NYMEX futures price. The pricing of ANS crude cannot be compared to the pricing of crude oil produced in California, however. Prices in California derive from the same or similar market factors which apply in other parts of the United States. The factors which drive ANS spot pricing are, on the contrary, unique to Alaska.

Alaska's crude oil is produced by three major producers. These are Exxon, ARCO Alaska, and Sohio, a subsidiary of British Petroleum ("BP"). Together they produce approximately 1.5 Million to 1.8 Million barrels of oil per day. During the past two years, virtually all of the oil produced by ARCO Alaska and by Exxon has gone to ARCO and Exxon refineries. During that period, the vast majority of spot sales of Alaskan crude oil have been made by one producer, BP. However, BP sells most of its production on term commitments and into the export market. It is estimated that less than half of BP's production, or only about 10% of Alaskan production, is sold on the spot market. The bulk of Alaska's production never enters the spot market and has no impact on market value. To value all West Coast production by reference to sales by a single company on what amounts to one tenth of Alaska's production is inequitable.

Moreover, the standard pricing method for spot sales of Alaskan production obscures the value of the crude oil. All spot sales are made on a delivered basis, which means that the terms of the sale include delivery of the crude oil, on seller-controlled vessels, to the purchaser's designated discharge point, such as its refinery. The crude oil purchaser

may not take delivery at a location other than its discharge point without incurring a seller-imposed penalty, and it is impracticable, under Jones Act regulations, for a crude oil purchaser to provide its own transportation for the crude oil. The price charged by the crude oil seller is a single figure, which incorporates both the value placed on crude oil and the value placed on shipping, neither of which is identified. Further, the price charged by the seller depends on the discharge location and the tonnage capacity of the vessel utilized for the sale, though neither the delivery locations nor the vessel data are public information. No one, with the exception of the seller, knows the value placed on the crude oil or the transportation components of the price. Consequently, absent disclosure by the seller of extensive information which has been heretofore kept private, and which varies from sale to sale, there is no way of knowing, or even making an educated guess, whether the price charged in any particular sale is a "market" price.

Most importantly, California's heavy crude oil and Alaska's light crude oil are not comparable in the market place. Most California production is heavy oil, which cannot, absent extra processing in a catalytic cracker or a coker, be used to obtain products other than heavy-ends such as asphalt. ANS, which is a light crude oil, can be processed into gasoline, jet fuel, and other light end products with less sophisticated refining capacity. Depending on refinery capabilities, refiners have a clear preference for one type of crude oil over the other and would not deem the two types of crude oil to be interchangeable. Generally, a refiner which buys the lower-priced California crude oil would not consider buying the higher-priced ANS; and a refiner which buys ANS would not be able to process California crude oil in its refinery.

In the preamble to the proposed rule, MMS calculated that the value of heavy crude oil from the Midway-Sunset field in California would be, using the adjusted ANS price, \$16.27 per barrel for September 1996. In reality, the September average spot price for Midway-Sunset crude oil, as reported by the Dow Jones Telerate, was just \$15.72 per barrel; and the posted price averaged \$15.98 per barrel for the month, finishing the month at \$16.25 per barrel. The September average spot price reported by Platt's Oilgram for Kern River heavy crude was only \$15.67 per barrel. Clearly, even after the application of differentials, MMS would attribute a higher value to California crude oil than the price a producer is, in the real world, able to obtain for its production. The result would be that the California producer would be assessed royalty on a price that is higher than the price he is able to obtain and thus, in actuality, bear a royalty burden higher than that contemplated by the oil and gas lease and higher than the burden borne by Alaska producers.

In summary, the vast majority of Alaskan crude oil which enters the spot market is sold by a single producer, which sells on a single set of terms, at a price in which the cost of crude oil is not distinguished from the cost of transportation. The factors which drive ANS spot price are singular, and certainly not equitable indicators of the factors which influence California prices. To proclaim ANS spot prices the benchmark by which all West Coast crude oil sales are judged would do West Coast independent producers a serious injustice.

More generally, DPC's objections and concerns with the adjustments are both legal and practical. First, we are unaware of any statutory authority for proposed 30 C.F.R. § 206.105(d)(3), 62 Fed. Reg. 3755, which would require each lessee to file Form MMS-4415 for each buy/sell agreement, exchange agreement, or "sale subject to balancing" in which the lessee or its affiliate engaged in, whether involving federal, state, or private lease oil, and without regard to where the exchange occurred in the stream of commerce.<sup>7</sup> Many of these transactions will be conducted by companies beyond the point of first sale or royalty computation for oil produced from federal leases. Section 103 of FOGDMA limits the Secretary's power to compel the creation and submission of documents to those pertinent to oil from federal and Indian leases through the point of first sale or royalty computation, whichever is later. He has no power respecting oil produced on private or state leases. 30 U.S.C. § 1713(a).

Furthermore, as a practical matter, the adjustments are likely to produce distortions in the value of the crude oil as MMS works upstream from Cushing to the thousands of producing federal leases. As explained earlier, by adjusting back from market centers, MMS captures royalty on the value added by aggregating large volumes of oil and selling them on the spot market. This value is in addition to the value added merely by the transportation of the oil. Yet this value does not exist at the lease where royalties are to be computed.

Special problems exist when a lessee sells at the wellhead. It does not have the information needed to adjust for transportation costs from its lease to the aggregation point. Its purchaser is unlikely to respond to inquiries about the purchaser's cost of transportation. The same lessee will not have the information needed to adjust for quality and location differences between the aggregation point and the market center.

MMS's solution to the lack of transportation data is simply to leave the lessee stranded. The proposed rule calls this deduction of transportation costs "optional." Proposed 30 C.F.R. § 206.105(c), 62 Fed. Reg. 3754. This "solution" is simply a demand for royalty on the value added by the movement of the oil down the stream of commerce, for royalty on phantom proceeds. Concerning the lack of information about exchanges, the proposed rule is more charitable. MMS proposes to compute its own number for lessees to use. But the data will be one to two years out of date, and MMS's number will be untestable because it is based on confidential business information. The only thing a lessee can be sure of about this number is that it will be wrong. MMS's number will not reflect the current market value of exchanges between aggregation points and market centers.

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<sup>7</sup> The proposed rule does not disclose, when a lessee is making the initial submission of these forms, how far back in time the lessee must review its records to report. 62 Fed. Reg. 3755.

MMS's consultants believe that MMS can reliably value all crude oil east of the Rockies by referring to Platt's index prices for West Texas Intermediate, West Texas Sour, Louisiana Light Sweet, Louisiana Heavy Sweet, and Wyoming Sweet. It is debatable whether Platt's accurately reflects trade differentials on a given day, but putting that concern aside, many of the volumes on which its prices are based are nominal. Guernsey, Wyoming, for example, does not have enough volume sold to establish a reliable value. At other locations, much of the crude that is traded is done during a one-week period. The daily arithmetic average of a Platt's differential would not accurately reflect the true trade differential for the bulk of the crude. Furthermore, it will be very difficult to compare the few crudes reported in Platt's to the variety of crudes traded. Koch's posted price bulletin has 49 different crude types. It is particularly hard, for example, to compare the value of West Texas sour crude to sour crudes in the Rockies or in the Southeastern United States.

Finally, the proposed rule does not provide a quality adjustment between lease and aggregation point. (Transcript of Houston hearing at 58-59 (remarks of Mr. Kosmin)). An illustration from the Gulf of Mexico highlights the problem. In January 1996, a lessee's arm's-length sale netted \$12.62 per barrel. Using MMS's proposed rule, the value would have been \$16.13, a \$3.51 difference. A chief cause for the discrepancy is MMS's failure to adjust for quality between the lease and the aggregation point. In this example, the gravity at the lease is significantly lower than the common stream at the aggregation point. The quality bank adjustment for that month was \$3.21.

Of course, adding a quality adjustment between the lease and the aggregation point still would not account for the difference between the actual arm's-length price at the lease and the proposed NYMEX netback value. In our example there remains a difference of \$0.30 between the wellhead value and the MMS proposed value. Information from subsequent months bear this point out. Even if MMS makes quality adjustments to the NYMEX price, there can be substantial unexplained differences, both higher and lower, from the market value of an arm's-length sale at the lease.

#### ALTERNATIVES

##### PRIME ALTERNATIVE: MMS SHOULD TAKE ITS ROYALTY IN KIND

DPC strongly endorses MMS's current initiative studying the option of marketing its own royalty oil. By taking oil in kind, MMS will gain three benefits. It will bring to an end its valuation controversies with lessees. It will have a better basis to judge whether following a pricing scheme like the one it would impose on lessees through this proposed rulemaking makes any business sense. And if such a scheme proves to make sense, MMS will, having taken the risks of the marketplace, earn the rewards that the market holds for risk-takers.

Except for certain marginal and isolated properties with production too small to be worth the administrative cost, MMS's commitment to royalty in kind should be total. For these "nuisance" properties, MMS would take royalty in value using the lessee's gross proceeds or, if the sale is not at arm's length, the nearest applicable benchmark price.

The procedure need not be complicated. MMS would take its royalty in barrels delivered at the point already established by the Bureau of Land Management onshore, or MMS offshore, for the measurement of volumes for royalty purposes. For OCS leases, the lessee is to deliver the oil free of cost to the lessor "on or immediately adjacent to the leased area...." Under more recent lease forms, MMS has the option of requiring the lessee to provide delivery of the oil "at a more convenient point closer to shore or on shore," provided that MMS reimburse the lessee for the cost of transportation to that point. Under the older lease forms, that option is the lessee's. Compare Form MMS-2005 (March 1986) § 6(c) with Form 3380-1 (February 1966) § 2(a)(3). For consistency's sake, MMS should take all royalty in kind on the lease. The lessee's sole obligation would be to deliver the correct number of barrels in a physical condition acceptable under contracts typical for the field.

MMS could then contract with a small number of companies with production and marketing experience to take the oil at that point for sale at a market center. These companies would act as MMS's marketing agents, would sell the oil for the best possible price, and would pay MMS for its barrels at the sales price minus transportation costs and a negotiated marketing fee. Using its agents in this way, MMS could hope to profit from taking the risk of price changes in the downstream markets. The payment of the marketing fee would transfer much of the administration of the downstream risks to the agents, further simplifying the federal role.

MMS could achieve dramatic administrative cost savings over its current system of royalty in value. The Province of Alberta, Canada, currently employs only 16 people to run a royalty in kind program which sells 146,000 barrels of oil per day. The Royalty Management Program, MMS, employs several hundred persons to assure that the proper value is paid on about 205,000 barrels per day. The agency could dramatically reduce the size of its workforce while -- if the premises of this proposed rulemaking are correct -- significantly increase its return on royalty oil. DPC encourages MMS to consider carefully the testimony presented at the Houston hearing on the benefits of the RIK option. Transcript pp. 137-48.

MMS already has the necessary statutory authority to institute a program like Alberta's. For onshore leases, its authority comes from section 36 of the Mineral Leasing Act, 30 U.S.C. § 192. Section 36 permits the Secretary to sell crude oil "upon notice and advertisement on sealed bids or at public auction...." *Id.* If he receives no acceptable bid, he may sell the oil "at private sale at not less than the market price...." Generally, of course, the Department has limited its sales of onshore royalty in kind to "refineries not having their own source of supply for crude oil...." *Id.* If the Department continues to find that "sufficient supplies of crude oil are not available in the open market to such refineries," it

may grant these refineries a preference and offer them oil "at private sale at not less than the market price...." *Id.* Nothing in the statute requires the Department to offer this oil for sale at the wellhead, nothing sets a price cap on what the Department may charge, and nothing prevents the Department from selling whatever oil independent refiners do not require on the open market.

For the OCS, the authority is similar. The Secretary may sell royalty oil "by competitive bidding for ... not less than its fair market value...." 43 U.S.C. § 1353(b)(1). Like the onshore statute, the offshore statute grants a preference for "small refiners." 43 U.S.C. § 1353(b)(2). If the Secretary determines that "small refiners do not have access to adequate supplies of oil at equitable prices," he may allocate oil among them by lottery or otherwise. The price in sales to small refiners is capped at the "fair market value," *id.*, a term defined by Congress. 43 U.S.C. § 1331(o). But the Secretary may sell quantities in excess of the needs of small refiners for at least the fair market value of the oil. As is the case onshore, the statute does not require the Department to deliver the oil at the wellhead; it may sell it for at least fair market value downstream.

#### SECONDARY ALTERNATIVE: REVISE THE BENCHMARKS

There are sales in the marketplace that even MMS's consultants would agree are at arm's length. At a minimum, for example, MMS should agree that a sale at the wellhead to a small, independent refiner is an arm's length sale. The refiner has every incentive to pay as little as possible, and the lessee has nothing to gain by selling at a below-market price. Similarly, a large class of independent producers would be regarded as arm's-length sellers even by the most suspicious MMS consultant. And if MMS continues to trust no other marketplace transaction at the wellhead, then surely MMS can trust itself. If MMS is reluctant to commit to a full RIK program, it should at least take RIK from every field where it distrusts the information from the wellhead market.

With this information available, MMS is well positioned to employ benchmarks to test the values received under non-arm's-length arrangements. DPC proposes that MMS end its reference to posted prices in the benchmarks. The agency has expressed publicly its commitment to change its reliance on posted prices. It has invested much effort in support of its desire to change. A change, whether warranted or not, will occur. But MMS should take care not to reject the lease market as a source of market information simply because of its desire to reject posted prices.

Instead, MMS should modify the benchmark system in its current rules. Exhibit 20 is DPC's proposed regulatory text. The benchmarks would work as they do under the current rules. A lessee selling not at arm's length would use the first applicable benchmark. When there are several transactions available for comparison under a given benchmark, the lessee's non-arm's-length price would be acceptable as long as it is in the range of prices in those several arm's-length transactions.

DPC has ordered the benchmarks to permit the lessee to use information that it would have readily available from its own arm's-length transactions. This approach will reduce the difficulties in obtaining information described in *Mobil Oil Corp.*

The first benchmark should be prices the lessee receives under other comparable arm's-length transactions in the same field or area. If the lessee has not received arm's-length proceeds for any significant level of production, it could use arm's-length prices it or its affiliate paid to third parties for sales of oil at the lease or prices bid in a tendering program of the kind described by Conoco at the Houston hearing. (See Transcript at 89-94.) A lessee's comparable sales to a small refiner under 43 U.S.C. § 1337(b)(7) would qualify under the first benchmark; but under DPC's fourth benchmark a lessee could use its proceeds from such a sale even if it were not comparable.

The fifth, sixth, and seventh benchmarks resort to information not readily available to the lessee: arm's-length proceeds received by third parties in the field or area, prices received by MMS from sales of royalty in kind in the field, and -- as a last resort -- a publicly reported price at the nearest market center netted back to the lease.

One difficulty with any benchmark system, of course, is assuring that lessees are aware of the benchmark prices. Antitrust laws place practical restrictions on what a lessee can research on its own. See *Mobil Oil Corp.*, 112 IBLA at 63-64 n.8. So each calendar quarter, MMS could publish -- by field and by grade of oil -- arm's-length sales values for wellhead sales for the prior quarter. Lessees whose sales during the prior quarter were not at arm's length would then have thirty days to pay the difference, if any, between what they reported as value on the MMS-2014 and the arm's-length value for the field.

The seventh benchmark should not be conceptually troubling to MMS, for it is consistent with the thinking behind the proposed rule. Once the NYMEX or ANS price is determined for the given month, the next step in MMS's proposal is for the lessee to adjust that price to reflect the different values the marketplace puts on oil in Cushing, Oklahoma, as opposed to oil in another market center, such as St. James, Louisiana. 62 Fed. Reg. 3742. MMS believes that this difference is accurately reflected in the differences between reported average spot prices at Cushing and St. James. 62 Fed. Reg. 3759 (Appendix F). Since MMS is basing its valuation scheme on them, MMS has offered no reason to suspect that these reported prices are any less reliable than a NYMEX futures price. Accordingly, MMS should consider, when no other benchmark applies, the use of prices at market centers as the starting point.

From this price, the lessee would have to make adjustments to reflect the costs and risks not borne by a producer selling at the wellhead. These would include deducting the market value added by transportation, which in most cases is approximated by the tariff approved by FERC, altering the price to reflect differences in the quality of the crude produced as opposed to the quality of the "marker" crude at the marketing center, and to deduct the costs of administering the risks of moving the oil from the wellhead to the market

center for a spot sale. These risks include risk of loss of the commodity, risk of environmental liability for mishaps in handling the oil, and the price risk associated with not selling the oil at the wellhead, but holding it in the hope of obtaining a higher price in a downstream spot market. These are all risks which neither the lessor nor the typical leasehold seller share. These risks cannot be undertaken in a free market without some corresponding reward. In calculating the value to be placed on this administrative deduction, MMS would be guided by the marketing fees negotiated with its agents under the royalty in kind program proposed in DPC's prime alternative. This would avoid the need for MMS to collect and digest thousands of exchange agreements in its attempt to reach the same result.

Ordinarily, the lessee would use the first applicable benchmark. However, the rule should also permit the lessee to use the second or third benchmark, even if the first is feasible, with MMS's prior consent.

#### ASSOCIATED COMMENTS

##### ROYALTIES ON BUYDOWNS

Proposed § 206.102(a)(5), 62 Fed. Reg. 3753, claims that a lessee's gross proceeds "include payments made to reduce or buy down the purchase price of oil to be produced in later periods." To the extent that the payments in question are to compensate the lessee for waiving rights under an existing contract, this position violates *IPAA v. Babbitt*, 92 F.3d 1248 (D.C. Cir. 1996).

In that case, the Department of Justice in its brief to the court vigorously argued that buydowns were subject to royalty and that buyouts and settlements of accrued take-or-pay liability were functionally no different.<sup>8</sup> In so doing, the Justice Department simply followed the position taken by Assistant Secretary Deer in *Samedan Oil Corp.*, MMS-94-0003-IND (Sept. 16, 1994), who reasoned that all three were indistinguishable: all were payments in anticipation of the lessee receiving a lower price in post-settlement sales of production. Slip Opinion at 12-13, 16 n.10, and 17.

The Department's views on buydowns were therefore squarely before the Court. That the Court addressed those views could not be clearer.

The take-or-pay settlements were of two types -- "**buydowns**" and "buyouts." In a **buydown**, the pipeline pays a cash lump sum to the producer in exchange for contract amendments (or a

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<sup>8</sup>Please refer to pages 7, 8, 10-11, 13-14, 15, 23-24, 26-28, 30, 39-41, 42-44 of the Brief of the Federal Appellees, and all of Appellees' Petition for Rehearing, in which the Department urged affirmance of its position on buydowns and failed to draw any distinction between buydowns and other forms of take-or-pay settlements.

new contract) providing for continued sale of the contracted-for gas at reduced prices. In a buyout, the pipeline pays a cash lump sum in exchange for release of the pipeline from the gas purchase contract. . . . Both types of contracts also often include a settlement of existing liability for previously incurred take-or-pay obligation.

92 F.2d at 1252 (boldface added). The Department litigated the issue of buydowns, and it lost. The Court rejected the Department's arguments as to both buydowns and buyouts, finding them indistinguishable under the gross proceeds rule.

Take-or-pay payments and contract settlement payments are functionally indistinguishable with respect to the calculation of royalties. Both types of payments satisfy outstanding take-or-pay obligations, and both types can be recoupable or nonrecoupable. The only difference is whether the payments follow negotiations between the parties over the cancellation of contractual obligations. We see no way in which the occurrence of these negotiations changes the functional nature of the payments for royalty purposes. The relevant question in both cases, under *Diamond Shamrock*, is whether or not the funds making up the payment actually pay for any gas severed from the ground. When take-or-pay payments (or settlement payments) are recouped, those funds do pay for severed gas. But when the payments (of either variety) are nonrecoupable, the funds are never linked to any severed gas. Therefore, no royalties accrue on those payments.

*Id.* at 1260 (footnote omitted). Like the Department of the Interior and the Department of Justice, the Court of Appeals saw no distinction between buyouts and buydowns.

To the extent there is no prior contract between the parties to be settled by the payment, our members are unaware of any instance, let alone custom, in the industry under which a purchaser has offered or would offer an up-front lump sum payment coupled with a below-market price for the oil.

CONCLUSION

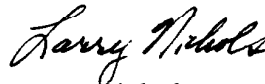
It has been the policy of the Interior Department, and still is the policy of the federal tax code,<sup>9</sup> that transactions between affiliated companies should be valued or taxed in a manner similar to comparable transactions between unaffiliated companies. MMS's proposed rule violates the policy of royalty parity and DPC opposes it.

Although DPC has offered extensive comments on the details of MMS's proposal, those are but trees in the forest. Viewing the problems in a broader perspective, MMS must recognize that years of disputes with lessees over the proper valuation of royalty is not an efficient use of taxpayer dollars, and resolving those disputes in thousands of individual appeals does not make private companies more profitable and competitive in the global marketplace. The more efficient solution to MMS's concerns over royalty value is for MMS to take its royalty in kind and obtain the best possible price for it.

Until that occurs, MMS must continue to recognize arm's-length transactions as the foundation for valuing royalties -- at the lease, not at Cushing, Oklahoma, or anywhere else in the midstream market for crude oil.

DPC is grateful for this opportunity to comment and looks forward to working with MMS on these important issues.

Sincerely,



Larry Nichols  
Chairman  
Domestic Petroleum Council

DC4560

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<sup>9</sup> See, e.g., *Texaco, Inc. v. Commissioner of Internal Revenue*, 98 F.3d 825 (5th Cir. 1996) *cert. denied*, \_\_\_ U.S. \_\_\_, 1997 WL 28623 (1997) (applying standard of comparable arm's-length sale to keep affiliated taxpayers "on a tax parity" with unaffiliated taxpayers).

## TABLE OF EXHIBITS

EXHIBIT 1	Preliminary Analysis of the Department of Interior, Minerals Management Service Proposed Rule Establishing Oil Value for Royalty Due on Federal Leases and on Sales of Federal Royalty Oil
EXHIBIT 2	Reed Consulting Group Briefing Paper
EXHIBIT 3	Briefing Paper: Sales Locations and Typical Terms
EXHIBIT 4	Micronomics, Inc. Briefing Paper: U.S. Crude Markets and Values
EXHIBIT 5	Summit Resources Briefing Paper: Existing MMS Payment Regulations Valuation Standards
EXHIBIT 6	Summit Resources Briefing Paper: "Overall Balance": Implied Exchange Transaction
EXHIBIT 7	Model Form Operating Agreement A.A.P.L. Form 610-1977
EXHIBIT 8	Model Form Operating Agreement A.A.P.L. Form 610-1982
EXHIBIT 9	Model Form Operating Agreement A.A.P.L. Form 610-1989
EXHIBIT 10	Repurchase Contract for 20% Set-Aside Volumes
EXHIBIT 11	May 31, 1996, Letter from Cynthia Quarterman, Director, Mineral Management Service, United States Department of Interior re April 4, 1996, Letter from Congresswoman Carolyn B. Maloney
EXHIBIT 12	Crude Oil Call in Farmout Agreement
EXHIBIT 13	Crude Oil Call in Assignment
EXHIBIT 14	Option to Purchase Production in Sale
EXHIBIT 15	Crude Oil Call in Assignment
EXHIBIT 16	Crude Oil Call in Sale
EXHIBIT 17	Preferential Right to Purchase Production
EXHIBIT 18	New York Mercantile Exchange Briefing Paper
EXHIBIT 19	Testimony of Jack Blomstrom
EXHIBIT 20	Proposed Revision to Crude Oil Benchmarks 30 C.F.R. § 206.102(c)

## Section 1

**PRELIMINARY ANALYSIS OF THE DEPARTMENT OF INTERIOR,  
MINERALS MANAGEMENT SERVICE PROPOSED RULE ESTABLISHING  
OIL VALUE FOR ROYALTY DUE ON FEDERAL LEASES  
AND ON SALES OF FEDERAL ROYALTY OIL**

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March 25, 1997

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location of the sale, and transportation costs. Under this rule, there would be no direct link between royalty values and actual contract prices for most transactions.

The proposed rule would add to the existing information burdens imposed on Federal lessees (and their affiliates) by requiring all lessees (and their affiliates) who engage in "non-arm's-length" oil sales to file a new form providing details on every exchange and buy/sell agreement that they enter into. One form would have to be filed each year for each such transaction, regardless of whether it involved a disposition of oil from a Federal lease, State lease, or private land. Based upon the text of the proposed rule as compared to the instructions for the new form, it is unclear who would be required to file the form.

The costs of the new filing requirement would include:

- ◆ the cost of the filings,
- ◆ the cost to lessees (and their affiliates) of changing internal company administrative, accounting and record-keeping systems to capture and integrate the information to be filed – with serious implications for smaller companies that do not have automated contract administration systems, and
- ◆ the inequities resulting from the requirement to file information on all crude oil exchange and buy/sell agreements, regardless of whether the oil involved comes from a Federal, Indian, State or private property.

The issue of who must file is in need of clarification from MMS.

Most of the information that would be collected on the proposed Form MMS-4415 will not be usable for MMS' intended purpose of estimating "location/quality differentials" between "market centers" and "aggregation points." As a result, unnecessary costs will be imposed on both the private sector and MMS itself – the latter because it will have to process and analyze information relating to a large volume of transactions that will yield no benefits in terms of its objective of developing more reliable estimates of the market value of the oil produced from Federal lands.

In addition to the costs imposed by new information collection requirements, the proposed method for valuing oil contains serious numerous flaws that would result in uncertainties and additional costs for lessees and, in some cases, additional administrative costs to the Federal government. We identify seven distinct problems:

- A. The methodology of using average spot price differences for establishing "locational price differentials" is problematic due to there being few transactions in some markets and the unevenness of contract volume over time. The proposed methodology will result in inaccurate location-based price adjustments and, thus, distorted estimates of value and will not accurately reflect quality factors.

PRELIMINARY ANALYSIS OF THE DEPARTMENT OF INTERIOR,  
MINERALS MANAGEMENT SERVICE PROPOSED RULE ESTABLISHING  
OIL VALUE FOR ROYALTY DUE ON FEDERAL LEASES  
AND ON SALES OF FEDERAL ROYALTY OIL

1. INTRODUCTION

A new rule proposed by the Department of Interior, Minerals Management Service (MMS) establishing oil value for royalty due on Federal leases, and on the sale of Federal royalty oil, would impose substantial new costs both on Federal lessees and on MMS itself.<sup>1</sup> The benefits of greater simplicity and certainty anticipated by MMS from the proposed rule either would not be realized or would be smaller than MMS expects. In this report, we consider various costs that would be imposed by the proposed rule and discuss various problems and ambiguities with the proposed approach to valuing oil for royalty purposes. We also question the underlying rationale of selecting any single price to represent market value when many different values, within a reasonable range, can all be true arm's-length prices.

Six companies provided specific information to assist in the analysis, and other companies provided general comments.<sup>2</sup> These companies represent a diverse group of types and sizes of producers. Among this group are companies that (1) have some production, while still making large net purchases of crude oil to support refinery operations, (2) buy and sell actively in addition to producing and refining, (3) exclusively produce oil without having a refinery, and (4) produce roughly the same amount of crude as needed to run their refineries.

All six companies provided information on the effects of the proposed rule, and four companies provided production statistics. The four companies account for approximately 19 percent of the royalty barrels produced on Federal lands during calendar year 1996 and for 20 percent of the total revenues collected during 1996. Of these four companies' production, 85 percent was from Federal offshore leases and the remaining 15 percent was from onshore leases.<sup>3</sup> These companies are holders of 2,157 Federal leases under which they are responsible for paying Federal royalties. Of these 2,157 leases, they operate and pay royalties on 1,115 of the leases, and another person is designated to operate and remit royalties on the remaining 1,042 leases.

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<sup>1</sup> All references to the proposed rule in this report, and page numbers shown in brackets, refer to 30 CFR Parts 206 and 208 as published in Federal Register, January 24, 1997, Volume 62, Number 16.

<sup>2</sup> These companies include: Chevron Corporation, Conoco Inc., Koch Industries, Inc., OXY USA Inc., Texaco Inc., and others.

<sup>3</sup> A very small percentage of total production was from Indian lands which is not covered by the proposed rule.

## 2. BACKGROUND

In this section, we provide background information relating to the proposed rule by describing data on Federal oil royalty payments from 1986 to 1996,<sup>4</sup> and by summarizing the current and proposed royalty valuation methodologies.

### PRODUCTION AND ROYALTY TRENDS

Production from Federal lands is reported annually by MMS. Three crude oil production categories are reported: from onshore properties, from offshore, and from Indian lands. While total domestic production has been declining at an average annual rate of 3 percent over the 1986 to 1996 period, crude oil production on Federal and Indian lands has begun increasing in recent years. Figure 1 shows the trends in both total domestic and Federal and Indian crude oil production. Beginning in 1992, Federal and Indian production began to diverge from the national trend. This increase in production is largely due to improved technology and increased offshore production on the Outer Continental Shelf.

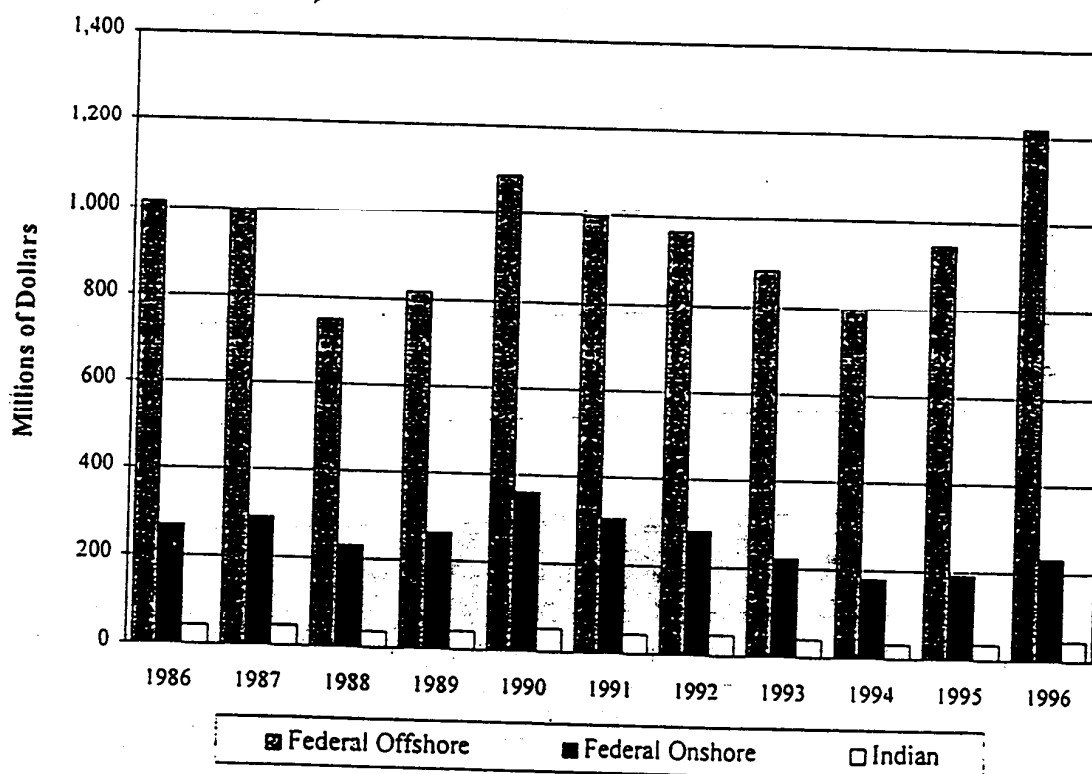
In 1996, crude oil production from Federal and Indian lands represented 24 percent of total oil production in the United States, with Federal offshore production accounting for 77 percent of this production. Under the lease contract between the U.S. Government (via the Secretary of the Interior) and the lessee, the lessee or its designee is required to pay a percentage of the production to the Federal government. Under the Minerals Leasing Act of 1920 and the Outer Continental Shelf Lands Act of 1953, royalties may be paid "in-value" or "in-kind." For Federal onshore lands, the customary royalty rate for oil is one-eighth of the production. For Federal offshore leases, the royalty rate generally ranges between one-sixth and one-eighth of production, although there are also some nontraditional royalty arrangements. In 1996, Federal lessees (or their designees) paid \$1.5 billion in crude oil royalties. Of that \$1.5 billion, \$1.2 billion was from Federal offshore oil, \$232 million was from Federal onshore oil, and \$45 million was from oil produced on Indian lands. Figure 2 shows Federal crude oil royalty payments by source for 1986 through 1996.

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<sup>4</sup> An 11-year period is appropriate in this context because industry economics changed dramatically after oil prices crashed at the end of 1985.

Figure 2

### Royalties from Federal and Indian Crude Oil Leases, 1986-1996

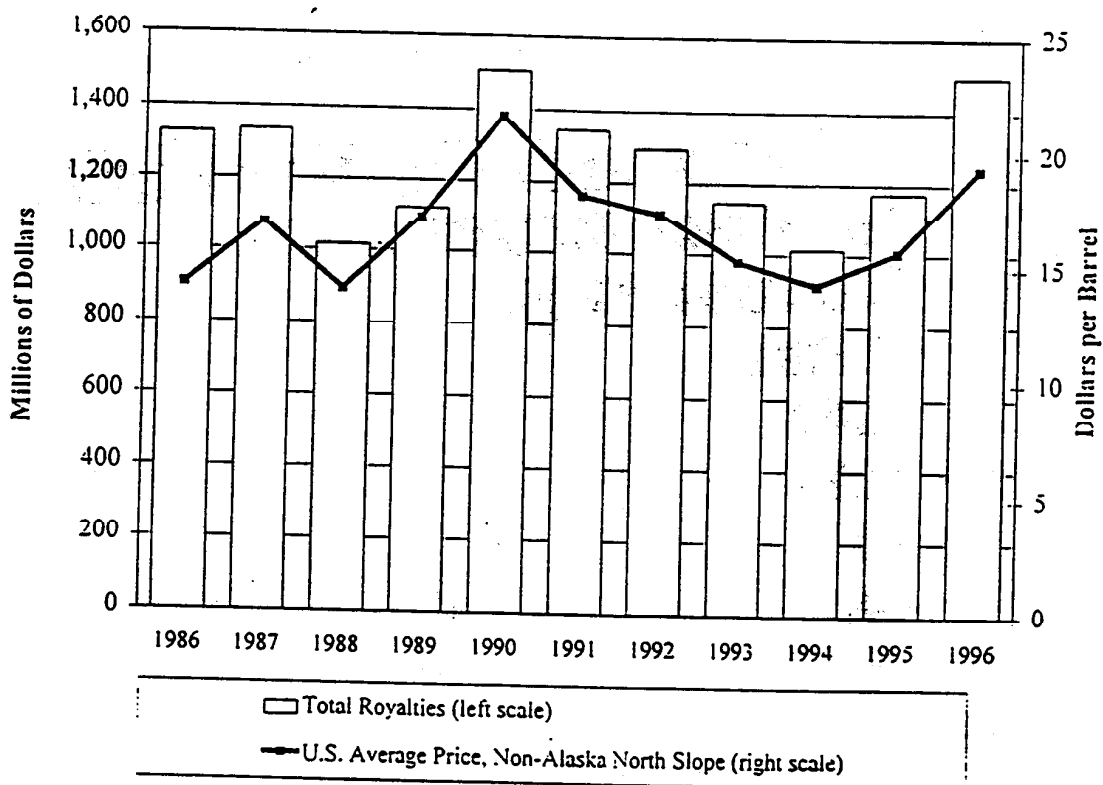


Source: *Mineral Revenues 1995* and preliminary 1996 data from MMS

Royalty oil taken in-kind from Federal leases totaled \$566 million in 1996, about 37 percent of the total royalty amount. Of this \$566 million, \$45 million was produced on Federal onshore leases, and \$521 million was from Federal offshore leases. Figure 3 shows the royalty value of oil taken in-kind from 1986 to 1996. While revenues derived from oil royalties taken in-kind from Federal onshore leases increased in 1996, the total number of onshore barrels sold declined by 5 percent. The increased royalty value resulted from higher oil prices. The number of barrels taken in-kind from Federal offshore leases increased dramatically in 1995 as five additional refiners joined the RIK program during the year. In 1996, the number of barrels taken in-kind from Federal offshore leases increased again, and the value of that oil also increased, along with oil prices generally (see Figure 4).

Figure 4

### Total Royalty Payments and Average U.S. Oil Prices, 1986-1996



Source: *Petroleum Marketing Monthly*, March 1997; *Mineral Revenues*, 1995; and preliminary 1996 data from MMS.

Under the Mineral Leasing Act, and the Mineral Leasing Act for Acquired Lands, states are paid 50 percent (generally 90 percent in the case of Alaska) of the lessees' payments for lease bonuses, royalties, late-payment interest, and rentals of public lands within mineral-producing states. Certain states with offshore production receive distributions equal to 27 percent of royalties under Section 8(g) of the Outer Continental Shelf Lands Act. The states actually receive a distribution of revenues net of the costs of administering mineral leases. As a result of the Omnibus Budget Reconciliation Act of 1993, MMS recovers 50 percent of the Federal Government's mineral leasing program administrative costs before disbursement to the states. As a result of these provisions, states will share MMS' costs of implementing any new rule.

In 1996, \$108.9 million or 24 percent of royalties collected from mineral leases was distributed to mineral-producing states from both offshore and onshore mineral activity. The Mineral Leasing Act of 1920 provides that states whose boundaries encompass Federal public domain mineral leases share in the revenue from those leases. Of these royalty distributions to the states, \$8.4 million were offshore oil royalties, and \$100.4 million were

If the oil is transferred in a non-arm's-length disposition to a "marketing affiliate," a defined term meaning an affiliate of the lessee which purchases only production from the lessee, the royalty value is established as the gross proceeds received by the lessee's affiliate in its first arm's-length sale.

If the oil is not sold under an arm's-length contract, then gross proceeds from the sale of the oil are calculated using the first applicable of the following five benchmarks:

1. the lessee's contemporaneous posted prices or oil sales contract prices used in arm's-length transactions for purchases or sales of like-quality oil in the same field, provided these are comparable to other posted prices or sales contract prices;
2. the arithmetic average of contemporaneous posted prices used in arm's-length transactions by persons other than the lessee for purchases or sales of significant quantities of like-quality oil in the same field;
3. the arithmetic average of contemporaneous posted prices used in arm's-length transactions by persons other than the lessee for purchases or sales of significant quantities of like-quality oil in the same area or nearby area;
4. prices received for arm's-length spot sales of significant quantities of like-quality oil from the same field (or same area) with adjustments for other matters unique to the circumstances of the lease or salability of the oil; or
5. a net-back method or any other reasonable method.

In using any of the above methods for both arm's-length and non-arm's-length contracts, the lessee may deduct a transportation allowance equal to the "reasonable, actual costs" of transporting the oil (Section 206.104). In certain circumstances, the lessee may use Federal Energy Regulatory Commission ("FERC") or State tariffs instead of transportation costs calculated using an MMS methodology.

The new rules proposed by the Department of the Interior, Minerals Management Service specify a very different approach for determining the value of oil for royalty purposes.

## PROPOSED RULE

In this section, we discuss the new reporting requirements and valuation methodology that have been proposed by MMS.

Royalty valuation at the lease for non-arm's-length transactions is proposed as follows: Where oil is transferred to an affiliate who later sells it at arm's length,<sup>6</sup> the value of the oil for royalty purposes will be either

1. the affiliate's arm's-length resale price (provided that neither the lessee nor its affiliate also purchases oil), or
2. a "monthly average" of the NYMEX futures price (for non-California and non-Alaska oil) or ANS spot price (for oil produced in California or Alaska), adjusted for location and/or quality differentials.

For all other cases (i.e., where the lessee or its affiliate refines the oil or disposes of it in a non-arm's-length transaction), the value of the oil at the lease for royalty purposes will be

1. for oil not produced in California or Alaska, a "monthly average" of the NYMEX futures price, adjusted for location and/or quality, or
2. for production in California and Alaska, the "monthly average" spot price for ANS oil delivered in California (either at San Francisco or Los Angeles), adjusted for location and/or quality.

Three adjustments to the "monthly average" NYMEX futures price are described by MMS:

1. a "location/quality differential" between the "index pricing point" (for example, West Texas Intermediate at Cushing, Oklahoma) and the appropriate market center (for example, Light Louisiana Sweet at St. James, Louisiana), calculated as the difference between the average monthly spot prices published in an MMS-approved publication at the respective locations;
2. a "location/quality differential" between the "market center" and a "major aggregation point" for oil from various sources, as either published by MMS or contained in the lessee's arm's-length exchange agreement (this adjustment would be based on the data collected on Form MMS-4415); and
3. the actual costs of transportation (as determined under existing valuation rules) from the "aggregation point" to the lease, or from the "market center" to the lease if the oil flows directly to a "market center."

<sup>6</sup> Using MMS' definitions, "Arm's-length contract means a contract or agreement between independent, nonaffiliated persons with opposing economic interests regarding that contract. Two persons are affiliated if one person controls, is controlled by, or is under common control with another person. Based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership: ownership over 50 percent constitutes control; ownership of 10 through 50 percent creates a presumption of control; and ownership of less than 10 percent creates a presumption of noncontrol. MMS may rebut this presumption if it demonstrates actual or legal control, as through interlocking directorates. MMS may require the lessee to certify the percentage of ownership or control. Aside from the percentage ownership criteria, contracts between relatives, either by blood or by marriage, are not arm's-length contracts. To be considered arm's-length for any production month, a contract must satisfy this definition for that month, as well as when the contract was executed." (Sec. 206.101 Definitions)

### 3. COSTS IMPOSED BY PROPOSED FORM MMS-4415

The proposed rule would impose substantial costs on Federal lessees, their affiliates, and their designees, as well as create substantial additional costs for MMS itself. Much of the cost will arise from requirements to file detailed information about oil transactions that will be of little or no use to MMS under its proposed royalty valuation methodology. Even the information that would be of use to MMS would be difficult to interpret and could not serve as the basis for statistically valid estimates. MMS has not reported to OMB or quantified any additional cost other than that imposed by the proposed Form MMS-4415. In this section, we briefly review the reporting requirements of Federal oil leaseholders under current law, review and critique MMS' estimate of the reporting cost under the proposed rule, and consider the costs imposed by the new filing requirement. In Section 4 of the report we will discuss some of the problems with and ambiguities of the proposed valuation methodology.

#### CURRENT REPORTING COST

Under current information reporting rules related to Federal oil royalties, three forms must be filed on a monthly basis with MMS. Lessees (or their designees) must file Form MMS-2014, "Report of Sales and Royalty Remittance," for each lease with the sales quantity, the sales value, the royalty quantity, and the royalty value. The form allows the reporting of information on multiple leases. Form MMS-3160 "Monthly Report of Operations" requires onshore well operators to report the location of each well; its production status; the volumes produced of oil, gas, and water; and the disposition of each product. A separate report, the "Oil and Gas Operations Report," also requires the reporting of production volumes by offshore wells. These latter two reports, when matched with Form 2014, are used by MMS to test royalty payments for completeness and accuracy.

Under the Paperwork Reduction Act of 1995, Federal agencies must report to the Office of Information and Regulatory Affairs (OIRA) of the OMB on the burdens imposed by their active information collections. According to information filed by MMS with OIRA, MMS has estimated that filings of Form MMS-2014 imposed 240,600 hours of labor costs on lessees in 1996, based on a total of 3,036,000 responses filed in that year (or an average of 253,000 forms per month). Information reported on the time cost imposed by Form MMS-3160 was grouped together with other forms and was not available separately.

Under the proposed rule, all of the reporting requirements of the current rule would remain intact, with the added requirement of completing Form MMS-4415 for each exchange agreement and buy/sell contract falling within the purview of the rule. Therefore, the proposed rule does not appear to be consistent with the goals of the Paperwork Reduction

The hourly labor cost assumed by MMS is significantly lower than the compensation assumed for its *own* employees who would analyze the data submitted. In its "Supporting Statement for Paperwork Reduction Act Federal Rule" submitted to OMB, MMS assumed that GS-9 employees would collect, sort and file the documents at a cost of approximately \$29 per hour, and that GS-12 analysts would analyze and publish the data at a cost of approximately \$43 per hour. Lessees would need to assign skilled professional analysts who are capable of understanding the various contracts and other sources from which information must be extracted in completing Form MMS-4415. Surely, such an analyst in the private sector would not cost less than a GS-9 Federal employee as MMS has assumed. One of the companies surveyed reported that the average salary, with benefits, of an appropriately skilled professional would amount to \$75,105 per year, or \$36 per hour (assuming 52 weeks per year and 40 hours per week). In addition, given the size of new workload volume imposed on lessees, it would be appropriate to allocate overhead costs to this effort, which the same company reported as \$8,040 per year. Due to time constraints, our preliminary survey data did not allow an assessment of the number of forms that will actually have to be filed per year by the average lessee, or the average time required to complete each form.

As mentioned above, MMS has not reported or quantified costs in addition to the cost imposed by Form MMS-4415. For example, the implications of the new reporting requirement for the other forms that must be filed have not been analyzed. It is foreseeable that the proposed Form MMS-4415 could have substantial implications for the information required on Forms MMS-2014 and MMS-3160, and the Oil and Gas Operations Report. Changes to these filings triggered by the new requirement would result in additional costs to lessees and MMS.

#### FURTHER COSTS RELATED TO PROPOSED FORM MMS-4415

In order to obtain information regarding the expected costs of the proposed reporting requirements, we conducted a limited survey of six significant oil producers who are Federal lessees. In conducting this survey, we asked each company to perform two tasks: First, we asked them to attempt to complete Form MMS-4415 for two or more transactions, and to provide an assessment of the process noting any problems that arose (e.g., problems in obtaining the required information or difficulties in interpreting what information was required). Second, we asked them to identify any significant changes that would be required to their administrative and information systems and processes to enable them to complete the forms for all of their contracts in effect for a filing year. Due to the ambiguities in MMS' instructions and the lack of ready access to some of the required information, no company was able to perform a complete analysis or develop a full cost estimate for this second part in the time permitted by the OMB comment period. Nevertheless, we were able to collect useful information on the nature of the changes required to be made by these companies.

transaction would not be informative about the price differential between the market center and any aggregation point. Further, many contracts exist between two aggregation points without going to a market center. Again, these forms will have no value to MMS. The only forms that will be useful to MMS for royalty valuation will be those covering transactions between major market centers and aggregation points.

A relatively simple set of realistic transactions can be used to illustrate how little of the data collected will actually be relevant to MMS. We start with a Federal lease off the coast of Louisiana at Ship Shoal, as illustrated in Figure 6 below. Crude oil from this lease enters a pipeline system at Eugene Island, which is an MMS-defined aggregation point. There it becomes part of a common stream of crude oil, as a result of being combined with oil from many other leases. From Eugene Island, crude flows to St. James, Louisiana, a major market center. Then, the oil is exchanged, but not physically delivered, via a buy/sell contract to Cushing, Oklahoma. A given volume of crude oil following this route can be the subject of numerous exchange agreements before reaching its ultimate user, but to keep the example simple we will consider just a few common types of transactions. In brief, the crude can be exchanged between any two points in the system without a price or a differential being computed at any intervening point.

Thus, the possible transactions include the following:

- |                                |  |
|--------------------------------|--|
| 1. Ship Shoal to Eugene Island | (lease to aggregation point)               |
| 2. Ship Shoal to St. James     | (lease to market center)                   |
| 3. Ship Shoal to Cushing       | (lease to index pricing point)             |
| 4. Eugene Island to St. James  | (aggregation point to market center)       |
| 5. Eugene Island to Cushing    | (aggregation point to index pricing point) |
| 6. St. James to Cushing        | (market center to index pricing point)     |

Of these six possible transactions, only one – the one between Eugene Island and St. James – will be of use to MMS in computing the intended adjustments. All the other transactions will have to be reported, but might just as well be discarded because MMS has no intention of publishing oil price differentials for these combinations. The methodology reflected above denotes only a single example of the lack of utility of the required information as it relates to its intended use. Further, MMS' proposed methodology contemplates two other "adjustments." A transportation cost adjustment is allowed between the lease and the aggregation point, and a third adjustment is intended to reflect differentials between market centers and the "index pricing point." Where transactions occur across multiple points in this stream, such as from Ship Shoal to Cushing, MMS will have no way to disentangle the cost of the separate legs of the trip because they will not be reported on Form MMS-4415, and indeed they could not be reported because intervening prices or differentials are never agreed to or specified in the course of commerce.

*B. The new form would impose major systems costs to change internal company administrative, accounting, and record-keeping systems to capture and integrate new information – with serious implications for smaller companies that do not have automated contract administration systems.*

As noted earlier, in MMS' statement to OMB regarding the costs of the proposed rule, MMS stated that they "... do not anticipate any additional capital or start-up costs will be needed to provide the requested information."<sup>7</sup> Our interviews and supplementary information provided by companies, led us to conclude otherwise. It was clear from the information we gathered that the new rule would require significant changes in the companies' contract information and administrative systems. None of the companies maintain all of the information required on a single system, and some information needed to complete Form MMS-4415 simply is not currently collected or does not exist. In some cases, different pieces of information are held by different legal entities (such as in the case of a production company and a marketing company that are separate corporations under common control). Substantial systems design and reprogramming will be required to link existing systems, at a minimum. Some company systems were designed by consulting firms that will need to be hired to make modifications required by the MMS proposal. One company reported that this additional reporting requirement will likely make their existing system obsolete. Absent this requirement, they would continue to use the existing system, but the proposed new filing requirement is expected to force them to expend tens of millions of dollars to replace their system.

Smaller companies, such as small production and marketing companies do not have sophisticated computerized systems for storing and integrating the kinds of royalty reporting and sales contract information that they would be required to track under the proposed rules. Either they would incur large costs of manually tracking the information or would have to invest in a new automated system.

A different set of problems arises in the case of small producers or producers with small working interests whose production is sold by the well operator under a joint operating agreement. In many instances, the lessee merely receives the proceeds from the operator and is unaware of the specific terms of the crude oil sales. The operator may sell the lessee's production through a buy/sell or exchange agreement, which will trigger an obligation under the proposed rule for the lessee to file a Form MMS-4415. Under this circumstance, however, the lessee will have either no or insufficient knowledge on which to make the filing.

If a purchaser is currently paying royalties and filing the Form MMS-2014 on the lessee's behalf, the added responsibility for filing the new form may be viewed as excessive. The purchaser may decide either to begin charging the lessee for assuming this additional task or.

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<sup>7</sup> "Supporting Statement for Paperwork Reduction Act Federal Rule," para. 13.

3. The actual API gravity adjustments are not readily available and will have to be calculated and/or retrieved from financial records.
4. The "actual cost," as defined by MMS, of transporting crude oil from the property to "market centers" is not currently tracked. A procedure and data system would have to be developed to gather, analyze, and record this data.
5. Some of the required information currently is not maintained in any system and will need to be acquired or derived. One company reported that they did not currently maintain a contracts system electronically and would have to develop one in order to complete Form MMS-4415 on an ongoing basis. Our sample was comprised primarily of large companies; we would expect such problems to be even more common among smaller companies.

Assuming information is available or can be obtained, current systems will have to be modified at considerable expense to enable companies to efficiently complete Form MMS-4415. Financial systems will have to be merged with royalty reporting and contracts systems; downstream systems will have to be modified to interface with upstream systems; pricing systems would have to be modified to interface with aggregation systems. Making such modifications will require large initial investments in system design and programming time.

*C. Form MMS-4415 will be burdensome to the industry, will require a much greater effort to complete than is anticipated by MMS, and will result in data of questionable utility to MMS.*

Our survey of Federal lessees and interviews with company representatives revealed that gathering the information required for the proposed form would be much more time consuming than the 15 minutes assumed by MMS. Numerous difficulties and ambiguities were identified that would not only increase the effort required by lessees, but would reduce the information value of the data received by MMS. Furthermore, the filing requirement would impose disparate costs on different lessees entirely out of proportion to the number of leases each lessee owns or volume of oil each produces. Here, we summarize and discuss some of these issues.

1. In reviewing the transactions recorded on Form MMS-4415 by the companies we surveyed, we encountered cases of exchange and buy/sell transactions in which the information reported on the form will be either ambiguous or entirely useless to MMS in computing "location/quality" value differentials. For example, one company reported a buy/sell transaction where they sold 17 barrels of one kind of crude oil to another party and bought 100 barrels of another kind. In such a case, the difference between the financial flows on the buy and sell sides of the contract will represent the influences of both the (large) difference in volumes transacted and the difference in location and quality of the two volumes transacted. To add to the complication, this

not identified on the form as adjustments. In some cases such charges are explicit, while in others they are incorporated into the price for which the crude is sold.

6. There is a lack of uniformity in the use of location names. Different names appear to mean different things to different companies. Thus, two companies may report comparable transactions at the same location (such as an "aggregation point"), but MMS may not realize this fact if the two companies use different names for the same location.

*D. The new filing requirement would place very different costs on different lessees that are not related at all to the number of leases they own or the volume of oil they produce from a given lease.*

As noted previously, the new form would have to be filed for all barrels sold through an exchange or buy/sell contract by a leaseholder during a filing year, regardless of whether the particular transactions involved Federal lease oil. It is easy to see how this requirement will lead to costs being imposed on different lessees that are unrelated to and entirely out of proportion to the importance of Federal leases in their operations. Indeed, companies would be required to consider whether to continue conducting transactions involving Federal oil if the proposal is adopted because of the sizable reporting cost involved in the filing requirements. Consider, for example, two similar onshore leaseholders, each with production of 1,000 barrels per day, and each operating 50 leases with an average daily production rate of 20 b/d per lease with all oil disposed of through the same number of exchange or buy/sell contracts. Now, suppose the first leaseholder produces exclusively from leases on Federal lands and the second leaseholder produces from one Federal lease at 20 b/d and from 49 private leases for the remaining 980 b/d of production. Under the proposed rule, both leaseholders will face equal reporting costs.

In addition, the reporting costs imposed on different companies will depend on the structure of their contracting arrangements, independently of how many leases they hold. Reporting would be required for many different kinds of contracts ranging from long-term evergreen contracts where single contracts covering large volumes of crude oil may last for years, to spot transactions where more than 100 contracts might be written each month by a typical large integrated company. For example, two companies with the same number of Federal leases, producing the same volume of oil from those leases, will have vastly different reporting costs if one tends to engage in a few long-term evergreen contracts with large customers, while the other tends to engage in a large number of contracts with many small customers.

average market price of Light Louisiana Sweet crude at St. James will be \$19.25/bbl, while the average spot price will be \$19.39/bbl (14 cents higher). In this case, it is clear that the lessee will suffer, because the spot price measurement error will distort the relationship between prices at St. James and Cushing. Of course, the lessee could benefit under other market circumstances. The error will be greater the less frequent are spot transactions in the given market center and the more (and more suddenly) the market value of the crude changes over the month.

A reasonable solution to this averaging bias would be to compute volume-weighted averages of spot prices. With a weighted average, greater weight would automatically be given to those days where price discovery in the market was greatest, and thus to those prices where the information content is greatest. However, this will not be possible in practice because spot transaction volumes are not available from any published source.

In addition to the above problems with averaging *per se*, the proposed rule is unclear on how the averaging of spot prices is to be done in practice. MMS will approve several publications for spot price quotes, and it is unclear from the rule which publication or publications a lessee should use in any given instance. For example, if a lessee needs to calculate spot price differentials for West Texas Intermediate at Cushing, OK, and Midland, TX, it is unclear whether it should use prices from Platt's, Telerate or Petroflash, or all of these. Should lessees or their designated royalty payors subscribe to all approved publications relevant to their businesses (at a nontrivial cost) and shop among them for the average prices at each market center that would be most beneficial to the Government? Is the lessee free to shop among them for the price that would be most beneficial to itself? Or will it be required to take an average from among all approved publications quoting the relevant spot price? The rule provides no guidance on these questions.

*B. "Location/quality adjustments" based on MMS-4115 will not be accurate or statistically valid.*

There are serious questions regarding the statistical validity of the proposed method for capturing quality, location and transportation adjustments in the valuation process. The proposed rule indicates that MMS proposes to develop and publish a set of location/quality differentials between major "aggregation points" and "major market centers" based upon the information provided by lessees, their affiliates and/or their designees on Form MMS-4115. However, it may not be possible to derive statistically valid differentials based on such information because the adjustments contained in actual sales, exchange, and buy/sell agreements represent several factors that can be impossible to disentangle.

It is important not simply to average together all transactions between a given market center and aggregation point over a given year because the overall average will confound the effects of location, gravity, sulfur content, and even transportation costs (in addition to time, as discussed in point C below). Instead, in order for the differentials to be meaningful adjustments for market valuation, MMS will need to develop a schedule that provides

*D. Changes in the treatment of transportation allowances will result in substantial compliance and administrative costs, and will create inequities.*

The proposed rule eliminates the lessee's ability under current rules to apply for the use of Federal Energy Regulatory Commission (FERC) and State-approved tariffs when computing Federal royalties. Rather, lessees are required to use actual costs, even though in its section-by-section analysis of the proposed rule, MMS asserts that "MMS is not proposing to change the existing methods to calculate transportation allowances." [p. 3747] This requirement results in substantial compliance and administrative costs and creates inequities: substantial costs will be incurred by many pipeline companies, and competing shippers will not be treated consistently.

Interstate oil pipeline carriers must file tariffs with FERC. Since 1994, these tariffs are generally computed using an indexing methodology that eliminates the need to maintain records based on actual costs. The proposed rule would require companies to undertake the reconstruction of actual costs at substantial expense. The establishment of cost-based tariffs is a highly labor intensive process and often requires incurring outside consulting and legal fees that FERC was able largely to eliminate through regulatory action undertaken in 1993. Through the proposed rule, MMS effectively would eliminate all the cost savings that the FERC achieved in this area.

The disallowance of FERC or state tariffs does not extend to shippers actually paying such tariffs to unaffiliated pipelines. As a result, those shippers owning an equity interest in a pipeline would be required to use a cost allowance calculated according to the MMS rule, while competitors could collect higher actual tariffs for shipments through the same pipeline.

*E. By assuming a single crude oil price rather than a range of market prices that reflect actual arm's-length transactions, the valuation methodology will have distributional impacts that have not been considered by MMS.*

In addition to the problems discussed above with calculating meaningful averages, the averaging methodology will have distributional implications that MMS apparently has not fully considered. The implicit assumption underlying the proposed rule is that apart from location and quality differences, there is a single market price for crude oil. While our report is not intended to discuss at length the crude oil pricing issues raised by the proposed rule, we disagree with this fundamental assumption.

As defined in the proposed rule, an arm's-length contract "means a contract or agreement between independent, nonaffiliated persons with opposing economic interests regarding that contract." [Sec. 206.101 Definitions] On any given day, different independent, nonaffiliated persons in the same location will arrive at different prices for otherwise comparable crude oil. These prices will reflect not only general market conditions, but also the particular needs of the buyer and the seller. If a buyer needs to acquire an incremental supply of crude oil with

methodology, both sellers will pay \$750, or 12.5 percent of the \$6,000 average (a value that neither seller received). As a result, the owner who traded in the car pays a tax that is actually equal to 15 percent of the car's \$5,000 market value, while the owner who sold the car by advertising pays a tax equal to only 10.7 percent of the \$7,000 received. By imposing such an averaging rule, the government could be described as redistributing the tax burden through what appears to be an administratively simpler system. Unfortunately, such simplifications often come at the price of creating inequities.

Executive Order No. 12866, issued on September 30, 1993, provides federal agencies with guidance on the Administration's regulatory philosophy and principles and states:

*When an agency determines that a regulation is the best available method of achieving the regulatory objective, it shall design its regulations in the most cost-effective manner to achieve the regulatory objective. In doing so, each agency shall consider incentives for innovation, consistency, predictability, the costs of enforcement and compliance (to the government, regulated entities, and the public), flexibility, distributive impacts, and equity.*

The MMS proposal has important distributive effects and does not result in equity. It may lead to substantial winners and losers among lessees. Smaller lessees with lower volumes and fewer transactions may be particularly affected.

*F. Obtaining contract information from and providing it to a separate affiliated company will be difficult at best.*

Serious problems will be encountered by leaseholders in providing information to and receiving information from affiliates that are separate legal entities. There are significant questions regarding their ability to provide and receive information in some cases – especially, where the downstream affiliate of a producer is less than 100-percent owned by the leaseholder or where the leaseholder has an equity interest in an inter-state pipeline (as discussed in point D. of this section). The proposed rule establishes the following definition of affiliate control “ownership over 50 percent constitutes control; ownership of 10 through 50 percent creates a presumption of control; and ownership of less than 10 percent creates a presumption of noncontrol.” (Sec. 206.101 Definitions) While we understand MMS' purpose in defining control in this manner, such a definition also imposes substantial compliance costs on the industry. Most larger oil producing companies have separate affiliates engaged in production, marketing, and transportation activities, in addition to integrated companies having other downstream entities. It is not uncommon for affiliated entities to be less than 100-percent owned.

Regardless of the degree of ownership, affiliated entities often have separate record-keeping, accounting, and administrative systems that do not readily communicate with each other. The complexities raised by this structure were readily apparent in our discussions with some of the companies. In most cases, computer systems are not integrated, and indeed, it was

to apply for a special calculation or it is obligated to apply. The uncertainty created by the "like quality" language of the rule will create an incentive for lessees to request special calculations for small differences between their oil and that typically sold at the nearby market center, in order to avoid the risk of either overvaluation or undervaluation – both of which could involve real monetary costs [page 3749]. The requests for exceptions driven by small quality and location differences will not only impose additional filing costs on lessees, but will impose corresponding increases in the workload and paperwork burden of MMS as it processes and responds to the requests. Uncertainty over the appropriate valuation could also lead to a greater need for MMS to conduct costly compliance audits.

## 6. CONCLUSIONS

Our preliminary analysis of the proposed valuation and reporting rule shows that (1) it would likely impose annual administrative costs on lessees that will be higher than MMS claims; (2) there would be significant one-time costs of adapting information and administrative systems to support the new filing requirements; (3) flaws and ambiguities in the valuation methodology will result in additional costs, inequities and uncertainty; and (4) the benefits of greater simplicity and certainty that MMS claims it will obtain from the new rule will be much smaller than it appears to believe.

The costs directly related to the new reporting requirement will include both the recurring effort required to fill out Form MMS-4415 for each exchange or buy/sell agreement, and the one-time costs of adapting companies' information and administrative systems to collect and maintain appropriate data items. Certain information that will be required on the proposed form (such as sulfur content, gravity, and transportation costs) are not maintained by companies in their extant information systems. In some cases, significant effort and cost would be expended to develop the required information.

In addition, seven distinct problems were identified dealing with the statistical validity of the proposed valuation methodology, changes in the treatment of transportation allowances, and various ambiguities in the proposed rule. Neither the spot-price-based location adjustments nor the MMS-calculated location/quality adjustments will reliably reflect the actual market values of crude oil transactions being conducted by lessees. These problems will lead to additional costs and uncertainty being imposed on the private sector. The option of issuing an Interim Final Rule in advance of the Final Rule would magnify the costs and uncertainty expected under the proposed rule.

In summary, the rule may increase government revenues from Federal oil leases, but would do so only by imposing large administrative costs, uncertainty and inequities on the private sector. Lessees will face substantially higher costs and will be forced to pay royalties on unrealistically high valuations that are not directly linked to their actual sales.

## Section 2



# Market Valuation of Domestic Crude Oil for Royalty Purposes

Presented to the  
Minerals Management Service

by  
Mike Harris



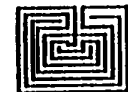
Reed Consulting Group

August 22, 1996

# MIMS Questions

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- ☐ What does posted price actually mean? -- Is it an offer to buy? Is it different today vs. in the past?
  - ▶ Traditionally an offer to buy -- a firm offer?
  
- ☐ What percentages of purchases or sales are made at posted prices?
  - ▶ Traditionally a large portion of sales are made at posted prices
  
- ☐ Can you explain why competing companies' posted prices have historically moved in tandem?
  - ▶ California: Market imperfections
  - ▶ East of California: "Rules of Thumb" and price leaders.



### Section 3

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## **Sales Locations and Typical Terms**

### **“Lease Activity”**

- **The first point of sale for most domestic crude is at the lease**
- **Significant portion of activity is between 3<sup>rd</sup> parties**
- **Posted prices are the predominate pricing basis**
- **Typical Terms:**
  - Guarantee lifting
  - Long-term commitment
  - Volume as produced
  - Quality as produced
  - Then-current market price (priced on *day-of-delivery*; forward pricing is not used)